Glen Canyon Dam Releases – Economic Considerations

David Marcus

February 28, 2009

I. Introduction

Glen Canyon Dam, located directly upstream of Grand Canyon National Park, controls the flow of the Colorado River through the Grand Canyon. Releases from the dam currently fluctuate hourly, daily, monthly, and annually in response to both hydrology and changing electricity demand and prices. However, under a "Seasonally Adjusted Steady Flow" (SASF) alternative, as described in the March 1995 Final Environmental Impact Statement (FEIS) for operation of Glen Canyon Dam, monthly volumes would change and daily fluctuations would largely cease.

Section II of this report analyzes how changing the release pattern would affect the economic value of power generated at the Glen Canyon Dam powerplant, and how those changes would in turn affect the cost of electricity to consumers throughout the 6-state area where Glen Canyon Dam generation is sold. Section III of this report summarizes the results from Section II, and concludes that the total dollar cost of changing dam operations would be small, and the impacts on individual customers would be very small indeed.

II. Analysis

A. Basis for economic costs associated with different release alternatives

The Western Area Power Administration (WAPA) markets the electricity generated at Glen Canyon Dam, and other smaller facilities in the Colorado River Storage Project (CRSP) system of reservoirs. CRSP generation is sold at cost to Federal agencies, electricity generating cooperatives, and publicly-owned electric utilities within a six-state area consisting of the states of Arizona, Colorado, Nevada, New Mexico, Utah, and

Wyoming. Differences between the hourly CRSP generation and WAPA contracts are made up by WAPA sales and purchases into the larger wholesale market. Thus, any changes in Glen Canyon Dam operation will lead to changes in WAPA's market sales and/or purchases. The economic cost of changing from one pattern of Glen Canyon generation to another can thus be estimated as equal to the market value of the changes in generation in each hour, summed over all hours with changed generation. I have analyzed the costs associated with changing from current Glen Canyon Dam generation patterns to SASF, based on both recent historical data and on near-term future generation projections.

At the most general level, the economic costs associated with different release alternatives are due to timing effects. Changing from one release alternative to another does not change the total annual releases from Glen Canyon Dam, and does not cause any significant change in the total annual kilowatthours (kwh) generated at the dam.[1] The economic differences come from shifting water releases from months when electricity is more valuable to months when it is less valuable (or vice versa), and from shifting water releases from hours of the day when electricity is more valuable to different hours when it is less valuable. In general, changing from the current release alternative to seasonally adjusted steady flows will decrease the value of Glen Canyon Dam generation due to more night-time water releases and less daytime water releases. But it will increase the value of Glen Canyon Dam generation due to more summertime water releases and less wintertime water releases. The net effect, as discussed and quantified below, is a very slight decrease in the value of annual Glen Canyon Dam generation, which results in a very slight increase in costs to Glen Canyon Dam generation purchasers. The average

[1] There can be very minor differences in annual kwh generation between release alternatives due to different reservoir elevations during the course of a year under different release alternatives.

overall cost of Glen Canyon Dam generation to purchasers would remain well below its market value.

B. Analysis of costs associated with changing to seasonally adjusted steady flows (SASF) – modeling assumptions

To model impacts that would have occurred if SASF had been in effect during the most recent water year (i.e., WY2008; from October 2007 through September 2008), I used actual monthly releases from Glen Canyon Dam during the October 2007 through September 2008 period, actual prices for on-peak and off-peak electricity delivered at the Palo Verde trading point during the same period (taking into account Sundays and holidays as they affected which hours were on-peak and which were off-peak), actual on-peak and off-peak minimum release requirements, and actual daily fluctuation limits during that same period. I used actual Glen Canyon dam conversion efficiency data (for the amount of electricity produced per acre-foot of water released) for the period September 2007 – August 2008, the most recent 12-month period for which I had data. I assumed that releases would not be affected by WAPA customer loads, or constrained by ramp rate limitations.

To model SASF, I used the monthly release amounts shown in the 3/95 FEIS for Glen Canyon Dam operations at p. 32, with one small modification. I made a minor reduction of 50 cfs in the September release rate to make the total annual releases come out to the annual release rate of 8.23 million acre-feet described in the FEIS for low water years.

C. Analysis of costs associated with changing to SASF – methodology

For SASF, the methodology was very straightforward. I performed the SASF valuation for the period October 2007 to September 2008. I calculated the number of on-peak hours and off-peak hours in each month, based on National Electric Reliability

Council (NERC) definitions that are widely used in electricity marketing. I used that data to calculate monthly on-peak and off-peak water releases from Glen Canyon Dam. I converted the water releases to electricity generation using monthly conversion efficiency factors. Glen Canyon Dam conversion efficiency varies primarily due to reservoir elevation – the higher the water level in the reservoir, the more electricity can be generated from a given amount of water. WAPA data show a 7 percent variation between September 2007 and August 2008 in conversion efficiency.

I obtained monthly average on-peak and off-peak wholesale electricity prices based on daily prices reported by the trade publication Megawatt Daily for the Palo Verde trading hub. Palo Verde is a large trading location in Arizona, and is the closest location to Glen Canyon Dam at which a substantial amount of wholesale electricity trading takes place and is reported in the trade press.

Once I had monthly on-peak and off-peak prices and generation amounts, I simply multiplied them together to obtain the market value of Glen Canyon generation for each period, and summed the 24 periods (12 months, with both on-peak and off-peak periods in each month) to obtain an annual value. Note that the total market value of Glen Canyon Dam generation is not the amount wholesale customers actually pay for Glen Canyon Dam generation. This is because most CRSP generation is sold by WAPA under long-term contracts at cost-based prices that are well below today's market prices. However, WAPA makes up the differences between contractual deliveries and CRSP generation through market operations, and passes those costs through to its customers. Changing Glen Canyon Dam operations will not change long-term contracts. Thus, any changes in generation patterns will cause offsetting changes in WAPA market purchases (or sales), meaning that the market value of Glen Canyon Dam generation is an appropriate measure to use to determine the value of **changes** in Glen Canyon Dam generation.

For the existing modified low fluctuating flow ("MLFF") operating policy, the analysis was more complex. I calculated the maximum average on-peak release rate for each month based on the total releases for that month, the number of on-peak hours in the month, the daily limit on changes in release rates, and the applicable minimum release rates for off-peak hours. This calculation assumed that WAPA will always attempt to maximize its on-peak generation and minimize its off-peak generation. In March 2008, I counted only releases used to generate power, and not the additional 93 thousand acre-feet that were released as part of a Beach Habitat Building Flow (BHBF) and bypassed the power-generating turbines.

After calculating on-peak and off-peak releases for each month, I used the same conversion efficiencies and prices as for the SASF analysis, and calculated the market value of Glen Canyon Dam generation for the on-peak and off-peak periods of each month. I did this calculation for actual release volumes in October 2007 through September 2008. The actual releases in the October 2007 – September 2008 year were about 7.95 percent higher than that the 8.23 Maf used for the SASF analysis, resulting in more electricity generation for that time period (under MLFF) than in the same time period under SASF.

After calculating the market value of Glen Canyon Dam generation under both current (MLFF) or proposed (SASF) operating rules, I then calculated the changes in (a) water releases, (b) electricity generation, and (c) the market value of generation, for both on-peak and off-peak time periods for each month. This calculation was done by subtracting the MLFF results from the corresponding SASF results.

For the historical period of October 2007 through September 2008, the analysis described above compared a SASF operating regime with 8.23 million acre-feet of releases to actual operations in which almost 8.9 million acre-feet of water were released (about 7.95% higher than 8.23 maf) through the Glen Canyon Dam powerhouse. Such a comparison is clearly incomplete, because SASF was not intended to change the annual release amounts from Glen Canyon Dam.[2] However, the FEIS does not specify how annual releases under SASF of more than 8.23 million acre-feet would be distributed across the different months. Thus, I used three separate methods to estimate the true impact of shifting to SASF under October 2007 through September 2008 conditions. In each case I assumed that releases under SASF would have been 7.95 percent greater than modeled up to that point, so as to match the actual releases in October 2007 through September 2008. Then I assumed that the value per kwh generated by the additional releases would have been either (1) equal to the average value per kwh of all other releases over the entire period, or (2) equal to the average value per kwh of all other off-peak releases over the entire period, or (3) equal to the value per kwh of off-peak releases during the lowest-market-value month of the entire period (i.e., September 2008). The third of these methods produces what I consider to be a lower bound for the value of the incremental electricity resulting from releases of 8.9 maf of water rather than 8.23 maf.

D. Analysis of costs associated with changing to SASF – results

Implementing SASF instead of MLFF in WY 2008 would have increased WAPA's market operations costs, and thus increased the cost of CRSP deliveries to retail customers, by $1.04 to $8.85 million. Table 1 compares MLFF (actual operations) in water year 2008 to what would have occurred if SASF had been in effect during the same period. If the annual release above 8.23 Maf is valued at annual average prices, then the value of Glen Canyon Dam electricity produced under SASF would have been $1.04 million less than the value of electricity produced under MLFF. In the worst case, if the annual release above 8.23 Maf is valued at the lowest monthly off-peak prices of the year, then implementing SASF would have increased costs to retail customers by $8.85 million.

[2] The FEIS on Glen Canyon Dam operations shows average annual releases under MLFF and SASF would differ by less than 0.1 percent.

E. Analysis of costs associated with changing to SASF – caveats

The analysis described above assumes that WAPA would maximize the value of Glen Canyon Dam electricity generation by shifting water releases as much as possible into on-peak time periods and out of off-peak time periods. To the extent WAPA does not do so, the analysis overstates the value of electricity generation under MLFF. There are at least two reasons why my analysis does indeed overstate the value of current generation, with no corresponding overstatement of the value of generation under SASF. First, WAPA is constrained by ramp rate limitations under MLFF. Thus, while daily increases of up to 5000 cfs are allowed in all months, hourly increases of 5000 cfs are not allowed. My modeling, by ignoring ramp rate constraints, overstates WAPA's ability to maximize on-peak generation, and thus overstates the value of generation under MLFF. Under SASF, ramp rate constraints are not binding and do not affect the results. Second, WAPA schedules releases from Glen Canyon Dam taking into account its customer loads, rather than simply maximizing the value of Glen Canyon Dam generation and making up all mismatches between WAPA generation and WAPA loads with market purchases and sales. Thus, under MLFF operating criteria, some on-peak hours Glen Canyon Dam generation could have been higher than it actually was, and in some off-peak hours Glen Canyon Dam generation could have been lower than it actually was. By not modeling on-peak hours when WAPA responds to its customers' load by reducing generation below allowable upper limits (or off-peak hours when it increases generation above allowable lower limits), I have overstated the value of generation under MLFF. Under SASF, customer loads do not affect Glen Canyon Dam generation and thus do not affect the results. I assumed that SASF would not include beach-building flows, or habitat maintenance releases in excess of the capacity of the Glen Canyon Dam turbines. During the March 2008 beach-building experiment, releases in excess of 26,000 cfs did not pass through the Glen Canyon Dam powerplant, and did not generate any electricity. A total of

93 Kaf of water was released without generating electricity. Under SASF, such bypass flows reduce generation during both on-peak and off-peak periods. Under MLFF, it is possible that a disproportionate amount of the reduction in power generation will be shifted to off-peak periods, and thus the net cost of beach-building flows will be lower under MLFF than under SASF. I have not quantified this potential effect of changing to SASF.

I used actual on-peak and off-peak energy prices from October 2007 through September 2008 in my analysis. The 2007-08 time period was characterized by a boom and bust in world oil prices, which was paralleled by similar trends in U.S. natural gas prices. In the western U.S., the marginal source of electricity generation is often (though not always, especially in low load periods) natural gas, and thus electricity prices tend to track natural gas prices. In the historical data, average monthly Palo Verde off-peak electricity prices rose from a low of $40/Mwh in November 2007 to a peak of $71/Mwh in April 2008, dropped to $57/Mwh in May 2008, rose back to $69/Mwh in July 2008, and then fell to a low of $39/Mwh in September 2008. Average monthly Palo Verde on-peak prices rose from $50/Mwh in November 2007 to a high of $100/Mwh in July of 2008 (with a one-month dip in May 2008), then fell to $55/Mwh in September 2008. To the extent future prices do not mimic the pattern of prices in 2007-08, the net costs of changing to SASF will differ.

Changing to SASF involves both eliminating intra-month shifting of generation into on-peak periods (because SASF has steady flows within each month) and also shifting of generation between months. The general pattern is that SASF defers some releases from the October-February period into the March-June period, and accelerates some releases from the July-September period into June. This pattern will result in higher reservoir levels under SASF from October through May, and lower reservoir levels in July-September. The net effect should be a slight benefit from switching to SASF due to higher average conversion efficiency of releases into electricity, an effect which I have not quantified. On the other hand, if electricity prices are higher later in the summer (August-September) than in the spring and early summer (April-June), which was not the case in 2008, then switching to SASF would be more expensive than my analysis shows.

I have used conversion efficiencies from September-October 2007 in calculating September 2008 generation (in Table 1), due to a lack of more recent data. These efficiencies are almost certainly slightly wrong, but affect both the SASF and MLFF analyses. It is not clear which direction the bottom line results would shift in with more accurate data. It is also not clear whether long-term average conversion efficiencies will be higher or lower than those I have used, since that depends on whether the long-term average elevation of Lake Powell is higher or lower than the average level in 2007-08.

I have modeled only one historical year. That year had releases for power generation of 8.885 Maf. 8.23 Maf is the minimum required release from Glen Canyon Dam, and it is the most frequently released amount (the mode, in statistical jargon), but it is not the mean release. Long-term average releases from Glen Canyon dam are projected to be around 8.56 Maf (3/95 FEIS, p. 179). My analysis does not capture the full range of potential hydrological regimes.

F. Analysis of costs associated with changing to SASF – retail customer impacts

The analysis described above, and presented in Table 1, shows decreases in the value of Glen Canyon Dam generation due to switching to SASF which range from $1.04 million per year to $8.85 million per year. I have performed a further analysis to show what those costs would mean for the average retail customer of the utilities served by WAPA. As explained in the "Operation of Glen Canyon Dam" FEIS (at p. 304), Glen Canyon Dam electricity is sold to utilities within a "six-State region" (Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming), who in turn resell to their retail customers. But utilities buying from WAPA serve only about 30 percent of those customers (FEIS,

p. 304). Thus, the estimated $1 million to $9 million annual cost of changing to SASF would be borne by those retail customers.

Glen Canyon Dam supplies only part of the electricity sold by WAPA (albeit a large part). WAPA supplies only part of the electricity purchased by WAPA customers. Electricity purchases are only part of the costs paid by retail electric utility customers (transmission costs, distribution costs, metering costs, and billing costs are examples of other costs included in electric bills). Thus, to evaluate the impact of changing to SASF on retail customers requires a review of the total electricity quantities purchased and prices paid by retail customers.

I have used the most recently available data (from 2006) to calculate that 33.8 percent of the electricity usage in the six-state area is by retail customers of publicly-owned utilities and cooperatives, and by federal agencies—the categories of groups that buy all or a part of their electricity from WAPA.[3] The remaining 66.2% of usage is by retail customers of for-profit utilities and direct use customers. The customers who used that 33.8 percent of 2006 6-state electricity sales paid a total of just under $5.5 billion to do so, at an average rate of $73.71 per megawatthour, or Mwh (1 Mwh equals 1000 kilowatthours, or 1000 kwh) of electricity. The average annual household usage in 2006 was 10.2 Mwh for the year, with average usage varying by state from a low of 7.1 Mwh per year in New Mexico to a high of 12.4 Mwh per year in Arizona.

I have calculated how the impacts of changing to SASF (between a $1.04 and an $8.9 million cost increase) would affect the average residential household in the 6-state area, based on the above figures. Assuming cost changes were spread evenly to all retail customers in proportion to their energy use, 66.2% of retail customers (those who do not receive power from WAPA) would see no impact. The other 33.8% would face rate

[3] Consistent with the 2006 data, the 1995 FEIS estimated that 30% of power users in the 6-state area bought their power from non-profit entities (i.e., Federal agencies, cooperatives, and publicly-owned utilities).

increases ranging from 0.02 percent to 0.16 percent, or from $0.01/Mwh to +$0.12/Mwh (depending on how much of their power is derived from WAPA). The impact on the average residential household's monthly bill (of affected customers) would range from 1 cent per month to +12 cents/month in Arizona, the state with the highest residential electricity consumption, and would be lower in the five other states. Averaged across all 6 states, changing to SASF might cost the affected one-third of residential customers an average of a penny a month, or it might cost them as much as just over a dime per month.

Averaging the cost of a change in Glen Canyon Dam operations over all users in the six-state area (including customers who do not acquire power from WAPA), the average impact of changing to SASF for all residential customers in the 6-state area would be an increase of between 0.4 cents and 3.4 cents per month. The computations described in the preceding paragraphs are shown in Table 2.

An alternative approach to estimating the impact on residential customers if SASF had been in place during water year 2008 is consistent with the previous calculations. It shows that the CRSP provided about 6.9 percent of the electricity sold by municipal utilities, Federal agencies, and electric cooperatives in the 6-state region, and that a typical residential customer of a utility obtaining 6.9 percent of its electricity supplies from the CRSP would have had 3-6 cent per month increase in their monthly bill due to SASF, depending on which state they lived in. These numbers are consistent with the middle set of SASF costs calculated in Table 1 and their impacts as shown in Table 2. The calculations are presented in Table 3.

Table 3 goes beyond the data in Table 2 to also show the impact on residential customers of utilities obtaining 15, 50, or 100 percent of their electricity supplies from the CRSP. While the monthly bill increases go up as the percentage of reliance on CRSP increases, the total monthly bill goes down. This happens because CRSP generation, which consists primarily of generation from Glen Canyon Dam, is sold at prices below prevailing spot market prices. Thus, the customers who would theoretically face the greatest costs from a switch to SASF are also the customers obtaining the greatest benefit from below-market CRSP prices, and the benefit of below-market CRSP prices far outweighs any CRSP price increase attributable to a switch to SASF.

III. Summary of conclusions

Changing Glen Canyon Dam operations from MLFF to SASF would defer water releases from the fall and winter forward into the spring. It would accelerate water releases from mid and late summer into June. It would shift some releases during each month from on-peak hours to off-peak hours. Shifting releases would change the timing and value of electricity generation. Increased off-peak generation would decrease the value of Glen Canyon Dam generation. Shifting generation between months could either increase or decrease the value of generation, depending on the month. Based on historical data from the most recent water year, and based on actual prices during that year, shifting to SASF in water year 2008 would have decreased the value of Glen Canyon Dam generation, and thereby increased costs to end users, by between $1.0 and $8.9 million. Changes in the value of Glen Canyon Dam generation would result in changes in average residential electric bills in the 6-state area served by Glen Canyon Dam of zero for two-thirds of the customers in the 6 states. For the other third of the customers, the average residential household electric bill would have increased by between 1 cent per month and 10 cents per month. In Arizona, where residential customers use more electricity per capita than in the other five states, the average residential bill impact would have ranged from 1 cent per month to 12 cents per month.